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(54) Drill string diverter apparatus and method

(57) A diverter apparatus (15) comprises a tubular housing (70) defining at least one flow port (92) defined therethrough communicated with a central opening flow passage (94) of said housing (70); a closing sleeve (102) disposed about said tubular housing (70) being moveable relative to said housing (70) between a closed position (60) wherein said closing sleeve (102) covers said at least one flow port (92) to prevent flow therethrough and an open position (62) wherein fluid in said tubular housing may flow through said at least one flow port (92); and locking means for locking said closing sleeve (102) in said closed position (60) whereby vertical movement of the closing sleeve relative to said tubular housing (70) is prevented.

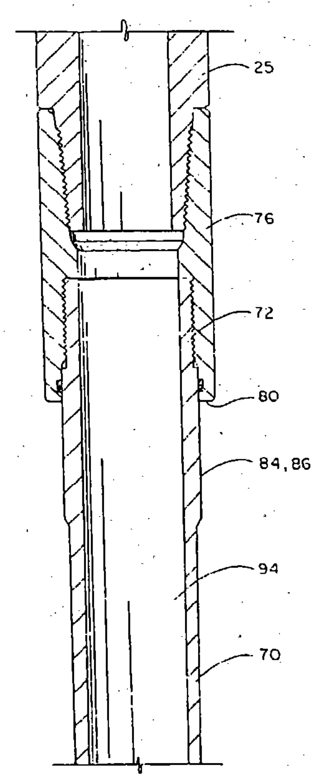

FIG. 2A

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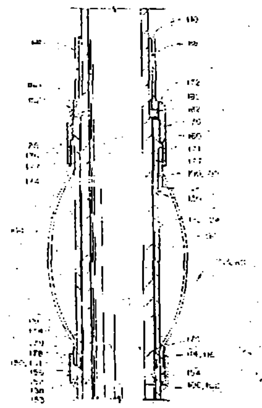


FIG. 2B

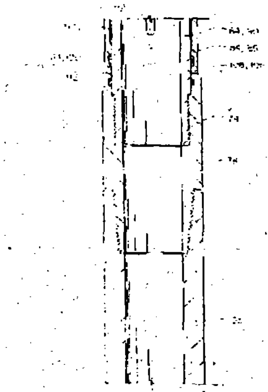


FIG. 2C

Description

[0001] The present invention relates generally to a diverter apparatus and a method of its use and more particularly to a drill string diverter apparatus which can redirect fluids that have entered a casing string while the casing string is being run into a wellbore.

[0002] In the construction of oil and gas wells, a wellbore is drilled into one or more subterranean formations or zones containing oil and/or gas to be produced. The wellbore is typically drilled utilizing a drilling rig which has a rotary table on its floor to rotate a pipe string during drilling and other operations. During a wellbore drilling operation, drilling fluid (also called drilling mud) is circulated through a wellbore by pumping it down through the drill string, through a drill bit connected thereto and upwardly back to the surface through the annulus between the wellbore wall and the drill string. The circulation of the drilling fluid functions to lubricate the drill bit, remove cuttings from the wellbore as they are produced and exert hydrostatic pressure on the pressurized fluid containing formations penetrated by the wellbore to prevent blowouts.

[0003] In most instances, after the wellbore is drilled, the drill string is removed and a casing string is run into the wellbore while maintaining sufficient drilling fluid in the wellbore to prevent blowouts. The term "casing string" is used herein to mean any string of pipe which is lowered into and cemented in a wellbore including but not limited to surface casing, liners and the like. As is known in the art, the term "liner" simply refers to a casing string having a smaller outer diameter than the inner diameter of a casing that has already been cemented into a portion of a wellbore.

[0004] During casing running operations, the casing string must be kept filled with fluid to prevent excessive fluid pressure differentials across the casing string and to prevent blowouts. Heretofore, fluid has been added to the casing string at the surface after each additional casing joint is threadedly connected to the string and the casing string is lowered into the wellbore. Well casing fill apparatus have also been utilized at or near the bottom end of the casing string to allow well fluid in the wellbore to enter the interior of the casing string while it is being run.

[0005] One purpose for allowing wellbore fluid to enter the casing string at the end thereof is to reduce the surge pressure on the formation created when the casing string is run into the wellbore. Surge pressure refers to the pressure applied to the formation when the casing being run into the wellbore forces wellbore fluid downward in the wellbore and outward into the subterranean formation. One particularly useful casing fill apparatus is disclosed in United States Patent 5,641,021 to Murray et al., assigned to the assignee of the present invention, the details of which are incorporated herein by reference. Although such casing fill apparatus work well to reduce surge pressure, there are situations where surge pressure is still a problem.

[0006] Liners having an outer diameter slightly smaller than the inner diameter of casing that has previously been cemented in the wellbore are typically lowered into a partially cased wellbore and cemented in the uncased portion of a wellbore. The liner is lowered into the wellbore so that it extends below the bottom end of the casing into the uncased portion of the wellbore. Once a desired length of liner has been made up, it is typically lowered into the wellbore utilizing a drill string that is connected to the liner with a liner running tool. The liner will typically include a well casing fill apparatus so that as the liner is lowered into the wellbore, wellbore fluids are allowed to enter the liner at or near the bottom end thereof.

[0007] Because the drill string has a much smaller inner diameter than the liner, the formation may experience surge pressure as the fluid in the liner is forced to pass through the transition from the liner to the drill string and up the smaller diameter drill string. Thus, there is a continuing need for an apparatus that will reduce the surge pressure on the formation when lowering a liner into a wellbore. Furthermore, because there are circumstances where it is necessary to manipulate the liner, there is a need for an apparatus that in addition to reducing surge pressure will allow for rotational and reciprocal movement and manipulation of the liner in the wellbore while the diverter is locked in a closed position.

[0008] We have now devised a diverter apparatus which solves or reduces problems associated with the prior art.

[0009] According to one aspect, the present invention provides a diverter apparatus for connecting in a drill string used to lower a liner into a wellbore, which diverter apparatus comprises: a tubular housing having an outer diameter smaller than an outer diameter of said liner and having a longitudinal central opening flow passage communicated with a flow passage of said liner, said tubular housing defining at least one flow port therethrough for communicating said central opening with an annulus defined between said tubular housing and said wellbore; a closing sleeve disposed about said tubular housing, said closing sleeve being moveable relative to said housing between a closed position wherein said closing sleeve covers said at least one flow port to prevent flow therethrough and an open position wherein fluid in said tubular housing may be communicated with said annulus through said at least one flow port; and locking means for locking, preferably permanently, said closing sleeve in said closed position whereby vertical movement of the closing sleeve relative to said tubular housing is prevented.

[0010] According to a further aspect, the invention provides a method for reducing surge pressure comprises providing a string of pipe having a diverter apparatus according to the present invention, lowering the pipe string including the diverter apparatus into a wellbore, allowing wellbore fluids to flow into the pipe string at a

point below the diverter apparatus and allowing wellbore fluid received in the pipe string to exit the pipe string through the at least one port.

[0011] The drill string diverter apparatus of the present invention comprises a tubular housing defining a longitudinal central flow passage, and at least one flow port and preferably a plurality of flow ports defined therethrough intersecting the longitudinal central flow passage. The tubular housing has an upper and lower end, preferably with an adapter threadedly connected at each end for connecting to a drill string or other pipe string thereabove and a liner running tool therebelow. A diverter apparatus can be connected in the pipe string which is disposed in a wellbore. Preferably, the wellbore has a cased portion having a casing cemented therein. The tubular housing and casing define an annulus therebetween.

[0012] The diverter apparatus of the present invention further comprises a means for selectively alternating between an open position wherein fluid may be communicated between the central flow passage and the annulus defined between the tubular housing and the casing in the wellbore through the flow ports, and a closed position wherein communication through the flow ports is blocked. A locking means for locking the diverter apparatus in the closed position to prevent the diverter from being inadvertently alternated back to the open position is also provided.

[0013] The means for selectively alternating preferably comprises a closing sleeve slidably disposed along an operating length of the tubular housing. More preferably, the closing sleeve is disposed about an outer surface of the tubular housing and is slidable between the open and closed positions.

[0014] Preferably, the closing sleeve has an outer diameter such that when the diverter apparatus is lowered into the wellbore, the casing disposed therein will engage the closing sleeve and hold the closing sleeve in place. Desirably, the closing sleeve is a closing sleeve assembly comprising a tubular sliding sleeve having a plurality of drag springs disposed about the outer surface thereof. The casing may engage the drag springs and urge the drag springs inwardly so that the sliding sleeve is held in place as the tubular housing, along with the remainder of the drill string, is moved vertically in the wellbore. Typically, the diverter apparatus will be in its open position wherein the sliding sleeve does not cover the flow ports and thus allows communication therethrough during the time the diverter apparatus is lowered into the wellbore. Advantageously, when the tubular housing is lowered into the casing, the casing will engage the drag springs so that the tubular housing will move downwardly as the casing holds the sliding sleeve in place. In this embodiment, the flow ports defined through the tubular housing will move downward relative to the sliding sleeve and will remain uncovered such that communication between the annulus and the central opening of the tubular housing is established. The closing sleeve, although it stays stationary along the operating length of the tubular housing can be said to move vertically relative to the tubular housing along the operating length thereof as the tubular housing moves vertically within the casing. Desirably, once the sliding sleeve reaches the upper limit of the operating length, it will move downwardly with the tubular housing and will stay in the open position. To move the diverter apparatus from the open to the closed position, downward movement is stopped and an upward pull is applied so that the tubular housing moves upwardly relative to the sliding sleeve until the sliding sleeve reaches the lower end of the operating length, wherein the sliding sleeve covers the flow ports thus placing the diverter apparatus in the closed position.

[0015] The locking means for locking the diverter apparatus in the closed position preferably comprises a J-slot defined on the outer surface of the tubular housing such that the diverter apparatus can be locked in the closed position simply by rotating the pipe string at the wellhead. Preferably the locking means further includes locking elements that are moveable along the outer surface of the tubular housing. In this embodiment, the locking elements will engage the J-slot to prevent rotation and vertical movement ofthe closing sleeve relative to the tubular housing, so that the liner can be reciprocated or rotated in the well and the diverter will stay locked in the closed position with no possibility of inadvertent opening.

[0016] Thus, when the liner is being run into the wellbore, and the diverter apparatus is in the open position, fluid can be communicated from the liner through the liner running tool into the tubular housing and out the flow ports into the annulus between the tubular housing and the previously set casing. An advantage of the apparatus and method of the invention is the provision of an outlet for the fluid in the liner, thereby reducing surge pressure on the wellbore.

[0017] A number of advantages accrue to the present invention. Firstly, it provides a means for reducing surge pressure on a formation and for reducing running time when lowering a liner into a partially cased wellbore. Secondly, it provides a diverter apparatus which can be selectively alternated between an open and closed position for selectively allowing and blocking communication between the central flow passage of a pipe string and an annulus between the pipe string and a casing cemented in the wellbore. Thirdly, it provides a drill string diverter apparatus for reducing surge pressure on a wellbore which can be locked in a closed position to prevent the inadvertent reopening and reestablishment of communication between the annulus and the drill string.

[0018] In order that the invention may be more fully understood, embodiments thereof will now be described by way of illustration only, in which:

[0019] FIG. 1 shows a schematic of the drill string diverter of the present invention disposed in a wellbore.

[0020] FIGS. 2A-2C show an elevation section view

of the drill string diverter of the present invention in a closed position.

[0021] FIGS. 3A-3C show an elevation section view of the drill string diverter of the present invention in an open position in a cased wellbore.

[0022] FIG. 4 shows a development of a J-slot in the tubular housing.

[0023] FIG. 5 is a section view of the tubular housing of the present invention taken from line 5-5 of FIG. 3B.

[0024] FIG. 6 is a section view of the tubular housing of the present invention taken from line 6-6 of FIG. 3B.

[0025] FIG. 7 shows an elevation section view of an additional embodiment of a drill string diverter of the present invention in an open position.

[0026] FIG. 8 shows an elevation section view taken approximately 60E from the view of FIG. 7 and shows a drill string diverter of the present invention in an open position.

[0027] FIG. 9 shows the elevation section view of FIG. 7 of the present invention in the closed position.

[0028] FIG. 10 shows a development of the J-slot in the tubular housing of the embodiment of FIG. 7.

[0029] Referring now to the drawings and more specifically to FIG. 1, a pipe string 10, including a drill string diverter 15 of the present invention, is shown schematically disposed in a wellbore 20 having a wellbore side or wall 21. Wellbore 20 has a cased portion 22 and an uncased portion 24. Pipe string 10 may include a drill string 25 connected at its lower end 27 to drill string diverter 15. Pipe string 10 may also include a liner 30 connected to drill string diverter 15 with a liner running tool 35. Liner 30 has outer surface 31 defining an outer diameter 32, and has inner diameter 33 defining a central opening 34.

[0030] Cased portion 22 of wellbore 20 includes a casing 40 cemented therein. Casing 40 has an inner surface 42 defining an inner diameter 44, and a lower end 46. As will be understood by those skilled in the art, wellbore 20 will typically be cased from lower end 46 of casing 40 to the surface. Thus, side 21 of wellbore 20 is defined in cased portion 22 of the wellbore by inner surface 42 of casing 40 and in uncased portion 24 is defined by the wall 43 of the uncased wellbore below the lower end 46 of casing 40. An annulus 48 is defined between pipe string 10 and the side 21 of wellbore 20. Annulus 48 is comprised of an upper annulus 50 and a lower annulus 52. Upper annulus 50 is defined between the inner surface 42 of casing 40 and the portion of pipe string 10 disposed therein. Lower annulus 52 is defined between the side 43 of the uncased wellbore and the outer surface 31 of liner 30.

[0031] As is apparent from the schematic, upper annulus 50 between liner 30 and casing 40 has a much narrower width than upper annulus 50 between drill string 25 and casing 40 and between drill string diverter 15 and casing 40. As will be explained in more detail herein, liner 30 has a means by which wellbore fluid can enter the liner. The wellbore fluid will travel upwardly in the direction of the arrows shown in FIG. 1 through central opening 34 and will pass through liner running tool 35 into drill string diverter 15. The wellbore fluid then may be communicated with upper annulus 50 through drill string diverter 15 above liner 30.

[0032] Referring now to FIGS. 2A-2C and FIGS. 3A-3C, diverter tool 15 is shown in its closed position 60 and its open position 62 respectively. FIGS. 3A-3C show the diverter apparatus disposed in casing 40. Diverter apparatus 15 comprises a tubular housing, or mandrel 70 having an upper end 72 and a lower end 74. Upper end 72 has threads thereon and is threadedly connected to an upper adapter 76. Likewise, lower end 74 is threadedly connected to a lower adapter 78. Upper adapter 76 is adapted to be connected to drill string 25 or other string of pipe thereabove. Lower adapter 78 is adapted to be connected to a crossover and liner running tool 35 and thus to liner 30. Although diverter apparatus 15 is shown as being connected at the lower end of drill string 25, drill string diverter 15 may be connected anywhere in a drill string so that several lengths of drill pipe or other pipe may be connected to lower adapter 78 and then connected to liner running tool 35. Adapter 76 defines a shoulder 80 and lower adapter 78 defines an upper end or shoulder 82, both of which extend radially outwardly from tubular housing 70.

[0033] Tubular housing 70 has an outer surface 84 defining a first outer diameter 86. At least one, and preferably two J-slots 88 are defined in outer surface 84. A development of the J-slots is shown in FIG. 4 and will be explained in more detail hereinbelow. Outer surface 84 also has a recessed diameter 90 radially recessed inwardly from outer diameter 86.

[0034] A plurality of flow ports 92 and preferably four flow ports 92 are defined through tubular housing 70 at recessed surface 90. Flow ports 92 are preferably spaced equally radially around tubular housing 70 and are located near lower end 74 thereof. Flow ports 92 intersect a central opening 94 defined by tubular housing 70. Central opening 94 is communicated with central opening 34 of liner 30 so that wellbore fluid entering liner 30 can pass upwardly therethrough into central opening 94, and when diverter 15 is in the second or open position 62 as depicted in FIGS. 3A-3C and in the schematic in FIG. 1, the wellbore fluid can pass through flow ports 92 into annulus 48 between tubular housing 70 and casing 40.

[0035] Diverter tool 15 further comprises a closing sleeve 100 disposed about tubular housing 70. Closing sleeve 100 comprises a tubular closing sleeve member 102, which may be referred to as a sliding sleeve 102 and a plurality of drag springs 104 disposed about tubular closing sleeve member 102. The embodiment shown includes eight drag springs. However, more or less than eight drag springs may be used.

[0036] Closing sleeve member 102 is sealingly and slidably received about tubular housing 70. Preferably, closing sleeve member 102 has an inner surface 106

defining a first inner diameter 108 that is slidably and sealingly disposed about outer surface 84, and has an upper end 110 and a lower end 112. Inner surface 106 defines a second inner diameter 109 at upper end 110 stepped radially outwardly from diameter 108. A lower seal 118 is disposed in a groove 120 defined on inner surface 106 of tubular closing sleeve 102 near lower end 112 thereof. An upper seal 114 is disposed in a groove 116 defined above groove 120 on the inner surface 106 of tubular closing sleeve 102. Lower seal 118 sealingly engages outer surface 84 of tubular closing sleeve 102 below ports 92 and upper seal 114 sealingly engages surface 84 above flow ports 92 when diverter apparatus 15 is in closed position 60. Thus, tubular closing sleeve 102 of closing sleeve assembly 100 sealingly engages tubular housing 70 above and below flow ports 92 and covers flow ports 92 when the diverter is in closed position 60 so that communication between central opening 94 and annulus 48 through flow ports 92 is prevented.

[0037] Closing sleeve member 102 has an outer surface 122 defining a first outer diameter 124. A plurality of upper spring alignment lugs 126 are defined by outer surface 122 and extend radially outwardly from outer diameter 124. Lugs 126 have an upper end 128 and a lower end 130. As better seen in FIG. 5, lugs 126 are radially spaced around tubular closing sleeve member 102 and define a plurality of spaces 132. A plurality of lower spring alignment lugs 134 are likewise defined by outer surface 122 and extend radially outwardly from first outer diameter 124. Lower lugs 134 have an upper end 136 and a lower end 138. As better seen in FIG. 6, lugs 134 are radially spaced about tubular closing sleeve 102 and define a plurality of spaces 140 therebetween. Preferably, there are eight upper lugs 126 and eight lower lugs 134 and thus eight spaces 132 and 140 respectively.

[0038] A lower spring retainer 150 is connected to outer surface 122 of tubular closing sleeve 102. Lower spring retainer 150 is substantially cylindrical and has an outer surface 152 and an inner surface 154. Lower spring retainer 150 is connected to and is preferably welded to the outer surface 122 of the tubular closing sleeve 102. Lower spring retainer 150 preferably has an L-shaped cross section with a vertical leg 151 and a horizontal leg 153. An annulus 156 is defined between leg 151 and outer surface 122 of closing sleeve 102.

[0039] A circular lug 160 is defined by outer surface 122 above spring alignment lugs 126. Circular lug 160 extends about the circumference of tubular housing 70 and is stepped radially outwardly from outer diameter 124. A distance 161 is defined between lug 160 and leg 153 of lower spring retainer 150. Outer surface 122 has threads 162 defined thereon above lug 160. A spring retaining sleeve 170 having an upper end 172 and a lower end 174 is threadedly connected to tubular closing sleeve 102 at threads 162 above circular lug 160. Retaining sleeve 170 extends downwardly past circular lug 160 and over a portion of upper spring alignment lugs 126. An annulus 171 is defined between retaining sleeve 170 and outer surface 122 of sliding sleeve 102 below circular lug 160. Drag springs 104 are disposed about tubular sliding sleeve 102, and as explained in more detail hereinbelow, drag springs 104 are connected to sliding sleeve 102 by placing the upper and lower ends thereof in annulus 171 and annulus 156, respectively.

[0040] Each drag spring 104 has an upper end 176 and a lower end 178, having engagement surfaces 177 and 179 respectively defined thereon. Surfaces 177 and 179 engage outer surface 122 of closing sleeve 102. Upper ends 176 of drag springs 104 are received in spaces 132 and lower ends 178 are received in spaces 140, and preferably have a uniform width. Upper ends 176 of drag springs 104 are received in annulus 171 and lower end 178 of drag springs 104 are received in annulus 156.

[0041] A pair of holes or ports 180 are defined through tubular closing sleeve 102 above threads 162. Each hole 180 has a spherical ball 182 received therein. Balls 182 are received in J-slots 88 and are covered by and thus held in J-slots 88 by retaining sleeve 170 which extends upwardly past holes 180.

[0042] Balls 182 are movable in J-slots 88 which are shown better in FIG. 4. J-slots 88 include a vertical slot 190 and a landing portion 192 having a lower edge 194, an upper edge 196 and a locking shoulder 198. J-slot 88 also includes an angular transition slot 200 extending from landing portion 192 to vertical slot 190.

[0043] Referring now to the schematic shown in FIG. 1, diverter 15 may be used in a pipe string 10 which comprises liner 30 and drill string 25 connected thereabove. Although the pipe string is designated as drill string 25 above liner 30, it is to be understood that the term drill string, when used in such context refers to any type of pipe string having a smaller outer diameter than the liner and utilized to lower the liner into the wellbore. Once the desired length of liner 30 has been made up, it is typically lowered through casing 40 and into the open uncased wellbore therebelow with drill string 25 or other string of pipe having a diameter smaller than the outer diameter 32 of liner 30. In the embodiment shown, drill string diverter 15 is connected to the liner running tool 35, but may be connected thereabove in drill string 25.

[0044] As is well known in the art, casing fill apparatus such as that shown in U. S. Patent 5,641,021, issued June 24, 1997, to Murray et al., the details of which are incorporated herein by reference, are used in liners to allow the liner to fill with wellbore fluid while it is being run into the wellbore. Although the fill apparatus described therein is particularly useful with the present invention, the diverter apparatus 15 may be used in combination with any type of fill apparatus that allows wellbore fluid into a liner as it is being run into a wellbore. One purpose of allowing wellbore fluid into the liner is to reduce surge pressure on the formation. Surge pres-

sure refers to the pressure applied by the liner to the wellbore fluid which forces the wellbore fluid into the formation.

[0045] When drill string diverter 15 is lowered into the wellbore, it will be engaged by casing 40 as shown in FIGS. 1 and 3A-3C. Casing 40 will compress, or urge drag springs 104 inwardly so that engagement surfaces 177 and 179 tightly grasp sliding sleeve 102. As shown in FIGS. 3A-3C, the overall length of the drag spring from its upper end to its lower end is less than distance 161, so that when casing 40 initially engages drag springs 104, ends 17b and 178 can move vertically along outer surface 122 as radially inwardly directed forces are applied to closing sleeve member 102 by drag springs 104. Once drag springs 104 are engaged by casing 40, the force applied to closing sleeve member 102 thereby is such that sleeve member 102 will be held in place by the drag springs. Thus, as tubular housing 70 moves vertically, closing sleeve 100 is held in place by casing 40 and will move vertically along an operating length 202 relative to tubular housing 70. Operating length 202 spans between lower end 80 of upper adapter 76 and upper end 82 of lower adapter 78. Downward movement of tubular housing 70 in casing 40 will cause tubular housing 70 to move downward relative to tubular closing sleeve member 102, and as such, the closing sleeve member 102 moves vertically upwardly relative to tubular housing 70 along operating length 202.

[0046] In closed position 60, spherical balls 182 are located at positions 182A as shown in FIG. 2B and FIG. 4. When diverter 15 moves to open position 62, communication between central opening 94 and annulus 48 is established through ports 92. Diverter 15 is moved to open position 62 from closed position 60 by lowering pipe string 10, and thus tubular housing 70 in casing 40. As tubular housing 70 moves downwardly, springs 104 are engaged by casing 40 so that closing sleeve 102 is held in place and ports 92 are uncovered. As pipe string 10 continues to move downwardly, tubular housing 70 will move relative to closing sleeve member 102 until upper end 120 thereof engages lower end 80 of upper adapter 76. When ends 86 and 120 are engaged, spherical balls 182 will be in position 182B as shown in FIG. 4, and closing sleeve member 102 will move downwardly as tubular housing 70 moves downwardly and will stay in open position 62. When tubular housing has moved downward so that ports 92 are uncovered, fluid that has entered liner 30 and is communicated with central opening 94 may exit through ports 92 into annulus 48 between tubular housing 70 and casing 40. In the absence of such ports, the transition from liner 30 to the smaller diameter drill pipe, along with friction created by the smaller diameter drill pipe can increase surge pressure. Thus, diverter apparatus 15 acts as a means for reducing surge pressure on a subterranean formation.

[0047] If, during the lowering of liner 30 into the wellbore it is desired to close ports 92 for any reason upward pull can be applied at the surface which will cause upward movement of tubular housing 70 in casing 40 relative to closing sleeve 100.

[0048] When upward pull is applied, tubular closing sleeve member 102 will be held in place by drag springs 104 and casing 40, and will move downward relative to tubular housing 70 along operating length 202 to closed position 60, wherein lower end 112 of tubular closing sleeve member 102 engages upper end 82 of lower adapter 78, and spherical balls 182 will move vertically in slots 190 to position 182A as shown in FIG. 4. Once end 112 engages upper end 82 of lower adapter 78, closing sleeve 100 will move upwardly along with tubular housing 70. In closed position 60, closing sleeve 102 covers ports 92 and blocks ports 92 so that communication therethrough between central opening 94 and annulus 48 is prevented. Diverter apparatus 15 can be moved once again to open position 62 simply by lowering the pipe string, and thus tubular housing 70, downwardly in casing 40 to move sleeve 102 upwardly relative thereto so that ports 92 are uncovered and communication between central opening 94 and annulus 48 is permitted therethrough. Thus, sleeve assembly 100 comprises a means for selectively alternating diverter apparatus 15 between an open position wherein fluid may be communicated between central opening 94 and annulus 48 through flow ports 92, and a closed position wherein closing sleeve 100 covers ports 92 so that flow therethrough is blocked.

[0049] When liner 30 reaches the desired depth in wellbore 20, diverter apparatus 15 may be locked in closed position 60 so that flow through ports 92 is blocked, and accidental, or inadvertent reopening is prevented. Liner 30 can then be cemented in the wellbore in typical fashion. To lock diverter apparatus 15 in closed position 60, downward movement of pipe string 10 is stopped and upward pull is applied so that spherical balls 182 move to position 182A along lower edge 194 of landing portion 192 of J-slots 88. Drill string 25 is then rotated until balls 182 engage locking shoulder 198 at position 182C. At position 182C, balls 182 are trapped between upper and lower edges 194 and 196 of landing portion 192 so that closing sleeve 100 will move vertically in casing 40 along with tubular housing 70, and diverter apparatus 15 stays in closed position 60. Thus, the J-slot, spherical ball arrangement provides a locking means for locking diverter 15 in its closed position 60.

[0050] If it is desired to unlock the tool while the tool is still in the wellbore, the diverter housing must be manipulated and rotated, in this embodiment, to the right so spherical balls 182 will pass over locking shoulder 198 into angular transition sleeve 200. Continued rotation will cause balls 182 to follow slot 200 until they are aligned with vertical slots 190 and thus can be moved from position 182A to 182B. Once diverter 15 is locked in closed position 60, it can not be unlocked accidentally, and typically there will be no need to unlock diverter apparatus 15 until it has been removed from the wellbore. However, if necessary, diverter apparatus 15 can be un-

locked as described.

[0051] The locking means may also comprise a locking sleeve releasably disposed in central opening 94. The locking sleeve would be attached in the tubular housing 70 above ports 92, and would have a seat for accepting a ball or dart. When it is desired to lock the diverter apparatus in its closed position, a ball or dart can be dropped and pressure increased to move the sleeve downward so that it covers ports 92. The tubular housing will have a shoulder or other means for stopping the downward movement of the sleeve. The ball seat within the sleeve must be detachable, or yieldable, so that the ball can be urged therethrough and cement can be flowed therethrough.

[0052] After diverter apparatus 15 has been moved to and locked in closed position 60, normal cementing operations can begin. Thus, as described herein, diverter apparatus 15 provides a means for reducing surge pressure when lowering a liner into a wellbore. The method for reducing surge pressure comprises providing a string of pipe having a diverter apparatus 15 connected therein and lowering the pipe string including the diverter apparatus into a wellbore. Surge pressure is reduced by allowing wellbore fluids to flow into the pipe string at a point below the diverter apparatus and by allowing wellbore fluid received in the pipe string to exit the pipe string through ports defined in the diverter apparatus. Such a method reduces surge pressure on a formation and reduces casing running time, thus providing a significant advancement over prior methods.

[0053] An additional embodiment of a diverter apparatus of the present invention is shown in FIG. 7 and is generally designated by the numeral 250. Diverter apparatus 250 is shown in FIG. 7 in an open position in a cased wellbore. Diverter apparatus 250 comprises tubular housing 70 which has adapter 76 connected at its upper end 72 and lower adapter 78 connected to its lower end 74. As set forth above, J-slots 88 are defined in outer surface 84 of tubular housing 70, which has a plurality of flow ports 92 defined therethrough at recessed surface 90.

[0054] Diverter tool 250 comprises a closing sleeve 252 disposed about tubular housing 70. Closing sleeve 252 comprises a closing sleeve member 254 and a plurality of drag springs 104. Closing sleeve member 254 has an inner surface 256 and an outer surface 258. A circular lug 260 is defined by outer surface 258. Circular lug 260 is substantially identical to circular lug 160 on closing sleeve member 102 of diverter apparatus 15, and is located substantially identically thereto. The portion of closing sleeve member 254, and thus closing sleeve 252 below circular lug 260 is substantially identical to the portion of closing sleeve member 102 and closing sleeve 100 below circular lug 160. Thus, closing sleeve 252 and closing sleeve member 254 include all of the features and elements described with reference to closing sleeve 100 and closing sleeve member 102 below circular lug 160.

[0055] Inner surface 256 defines an inner diameter 262 spaced outwardly from outer diameter 86 of tubular housing 70. Inner surface 256 defines a first or lower shoulder 264 extending radially inwardly from diameter 262. A second or upper shoulder 266 is defined by inner surface 256 and extends radially inwardly from diameter 262. Shoulders 264 and 266 define an inner diameter 268, and are preferably closely received about and engage outer diameter 86 of tubular housing 70. Closing sleeve member 254 has an upper end 270 that engages shoulder 80 defined by upper adapter 76 when diverter apparatus 250 is in open position 62 as shown in FIG. 7. Closing sleeve member 254 has a pair of ports or openings 272 that may be referred to as first or lower openings 272. Lower openings 272 are preferably defined through closing sleeve member 254 at the location of lower shoulder 264. A pair of second or upper openings 274 are defined through closing member 254, preferably at the location of second radially inwardly extending shoulder 266. Openings 274 are shown in FIG. 8.

[0056] A locking element 280, which preferably comprises a spherical ball 182, is received in each of lower openings 272. As shown in FIG. 7, and in the development of the outer surface of tubular housing 70 in FIG. 10, locking elements 280 are received in the vertical leg 190 of J-slots 88 when the diverter apparatus 250 is in open position 62. Vertical legs 190 of J-slots 88 are located 180° apart from one another around the circumference of tubular housing 70, along with ports 272 and lower locking elements 280.

[0057] Referring now to FIG. 8, an upper locking element 282, which preferably comprises a spherical ball 182 is received in each of upper openings 274. The upper pair of openings 274 and thus the upper pair of spherical locking elements 282 are positioned 180° apart. Upper ports 274 and upper locking elements 282 are preferably positioned about 60° around the circumference of tubular housing 20 from lower locking elements 280. This is seen better in the development view of FIG. 10 which shows the outer surface of the tubular housing laid out flat. As will be explained in more detail hereinbelow, diverter apparatus 250 may be moved to closed position 60 and rotated 60° so that upper locking elements 282 will be urged into the vertical legs 190 of J-slots 88 while lower locking elements 280 will be positioned in landing portions 194. Closing sleeve member 254 and thus closing sleeve 250 will be locked in place to prevent rotational and vertical movement of sleeve member 254 relative to tubular housing 70 so that as pipe string 10 is rotated and/or reciprocated in the wellbore, closing sleeve 250 will move with the pipe string and cannot be unlocked to uncover ports 92.

[0058] Closing sleeve member 254 has threads 290 defined thereon above circular lugs 260. A retaining sleeve 292 is threadedly connected to closing sleeve member 252 at threads 290. Retaining sleeve 292 has a lower end 294 that extends downwardly below circular lug 260 in the same manner as closing sleeve 170 on

diverter apparatus 15, and functions in the same manner as closing sleeve 170 below circular lug 160 described with reference to diverter apparatus 15. Retaining sleeve 292 is disposed about outer surface 258 of closing sleeve member 254 and extends upwardly beyond openings 272 to an upper end 296, which is positioned slightly below openings 274. Retaining sleeve 292 thus holds spherical locking elements 280 in place in openings 272 and J-slots 88. An outer surface 298 of retaining sleeve 292 has threads 300 defined thereon near the upper end 296 thereof.

[0059] A wedge 302 is disposed about closing sleeve member 254. Wedge 302 has an upper end 304 and a lower end 306 and extends downwardly such that wedge 302 covers a portion of port 274. Wedge 302 has an inner surface 308 which defines a tapered wedge surface 310 that engages spherical locking elements 282. Inner surface 308 defines a diameter 311 located upwardly from tapered wedge surface 310. Wedge 302 preferably includes a leg portion 312 and a head portion 314. Tapered wedge surface 310 is defined on head portion 314. Leg portion 312 has an outer diameter 316 and head portion 314 has an outer diameter 318. An upward facing shoulder 320 is defined by and extends between diameters 316 and 318.

[0060] An upper retaining sleeve 324 having lower end 326 and upper end 328 is threadedly connected to retaining sleeve 292 at threads 300. Retaining sleeve 324 has an inner diameter 330 disposed and closely received about diameter 318 of head portion 314 of wedge 302. A leg 332 extends radially inwardly from inner diameter 330 at the upper end 328 of retaining sleeve 324 and defines an upper inner diameter 334. A downward facing shoulder 336 is defined by and extends between diameters 330 and 334. An annular space 340 is defined by diameters 316 and 330 of wedge 302 and retaining sleeve 324, respectively. Annular space 340 has upper and lower ends 342 and 344 which comprise shoulders 336 and 320, respectively. A spring 346, which is preferably a plurality of stacked wave springs, is positioned in annular space 340 and engages the upper and lower ends 342 and 346 thereof to urge wedge 302 downwardly into engagement with spherical locking elements 282.

[0061] FIG. 9 shows the upper end of diverter apparatus 250 in closed position 60 and shows the position of upper locking elements 282. As shown therein, closing sleeve member 254 has been rotated so that locking elements 282 are positioned in vertical legs 190 of J-slots 88. Wedge 302 has been urged downwardly by spring 346 so that it engages spherical elements 282 to hold elements 282 in vertical leg 190 of J-slots 88.

[0062] It is understood that diverter apparatus 250 can be moved to open positions 60 and 62 in the same way as diverter apparatus 15. Thus, pipe string 10 may be reciprocated up and down so that closing sleeve member 254 moves vertically relative to tubular housing 70 along the operating length thereof. In open position 62, elements 280 and 282 are located at positions 280B and 282B as shown in FIG. 10. Movement of the diverter apparatus to closed position 60 is as discussed with reference to diverter apparatus 15 and simply requires pulling upwardly on the string so that closing sleeve 252 moves relative to tubular housing 70 until elements 280 and 282 are in positions 280A and 282A as shown in FIG. 10. The pipe string can be reciprocated such that the spherical elements 280 can be located anywhere within the length of vertical leg 190 between positions A and B as diverter apparatus 250 is alternated between open and closed positions 60 and 62. Spherical elements 282 will slide along outer diameter 86 of outer surface 84 of tubular housing 70 between positions 282A and 282B as the apparatus is alternated between open and closed positions.

[0063] When the desired depth has been reached, pipe string 10 can be rotated so that spherical elements 280 will be located at positions 280C and spherical elements 282 will be located at positions 282C. In position 282C, locking elements 282 will be urged inwardly and held in the vertical leg 190 of J-slots 88 by wedge 302. Such a position may be referred to as the permanently locked position 350. In permanently locked position 350, closing sleeve 250 cannot rotate or move vertically relative to housing 70, except for the distance between the upper and lower edges 196 and 194, respectively, of landing portion 192. Thus, diverter apparatus 250 has a locking means for preventing rotation and reciprocation of the closing sleeve relative to the tubular housing. In position 350, the closing sleeve will move with pipe string 10 and cannot be reopened either inadvertently or purposely without removing the apparatus from the well, thus permanently blocking ports 92. Thus, when diverter apparatus 250 is in position 350, the pipe string can be manipulated in any desired manner without fear of moving the closing sleeve to the open position and allowing flow through ports 92.

Claims

1. A diverter apparatus (15) for connecting in a drill string (25) used to lower a liner (30) into a wellbore (20), which diverter apparatus (15) comprises: a tubular housing (70) having an outer diameter (86) smaller than an outer diameter (32) of said liner (30) and having a longitudinal central opening flow passage (94) communicated with a flow passage (34) of said liner (30), said tubular housing (70) defining at least one flow port therethrough for communicating said central opening (94) with an annulus (50) defined between said tubular housing (70) and said wellbore (20); a closing sleeve (102) disposed about said tubular housing (70), said closing sleeve (102) being moveable relative to said housing (70) between a closed position (60) wherein said closing sleeve (102) covers said at least one flow port (92) to prevent flow therethrough and an open position

(62) wherein fluid in said tubular housing (70) may be communicated with said annulus (50) through said at least one flow port; and locking means for locking, preferably permanently, said closing sleeve (102) in said closed position (60) whereby vertical movement of the closing sleeve (102) relative to said tubular housing (70) is prevented.

2. An apparatus according to claim 1, wherein the locking means (182) is for permanently locking said closing sleeve (102) in said closed position (60) thereby preventing said closing sleeve (102) from rotating relative to said housing (70).

3. An apparatus according to claim 1 or 2, wherein said tubular housing (70) has at least one slot (88) defined in an outer surface (84) thereof, said slot (88) having a vertical portion (190) and a horizontal portion (192), said locking means comprising: a locking element (182) moveable with said closing sleeve (102); said housing (70) being rotatable relative to said closing sleeve (102), wherein rotation of said housing (70) causes said element (182) to move into said vertical portion (190) of said slot (88), thereby locking said sleeve (102) in place in said closed position (60).

4. An apparatus according to claim 3, wherein said locking element comprises at least one, and preferably two, upper locking element (282) and wherein said locking means further comprises at least one, and preferably two lower locking element (280), said lower locking element (280) being positioned in said vertical portion (190) of said slot (88) when said sleeve (102) is in said open position (62), and being located in said horizontal portion (192) of said slot (88) when said sleeve (102) is rotated to said locked closed position (60), said lower locking element (280) preventing relative vertical movement between said sleeve (102) and said housing (70).

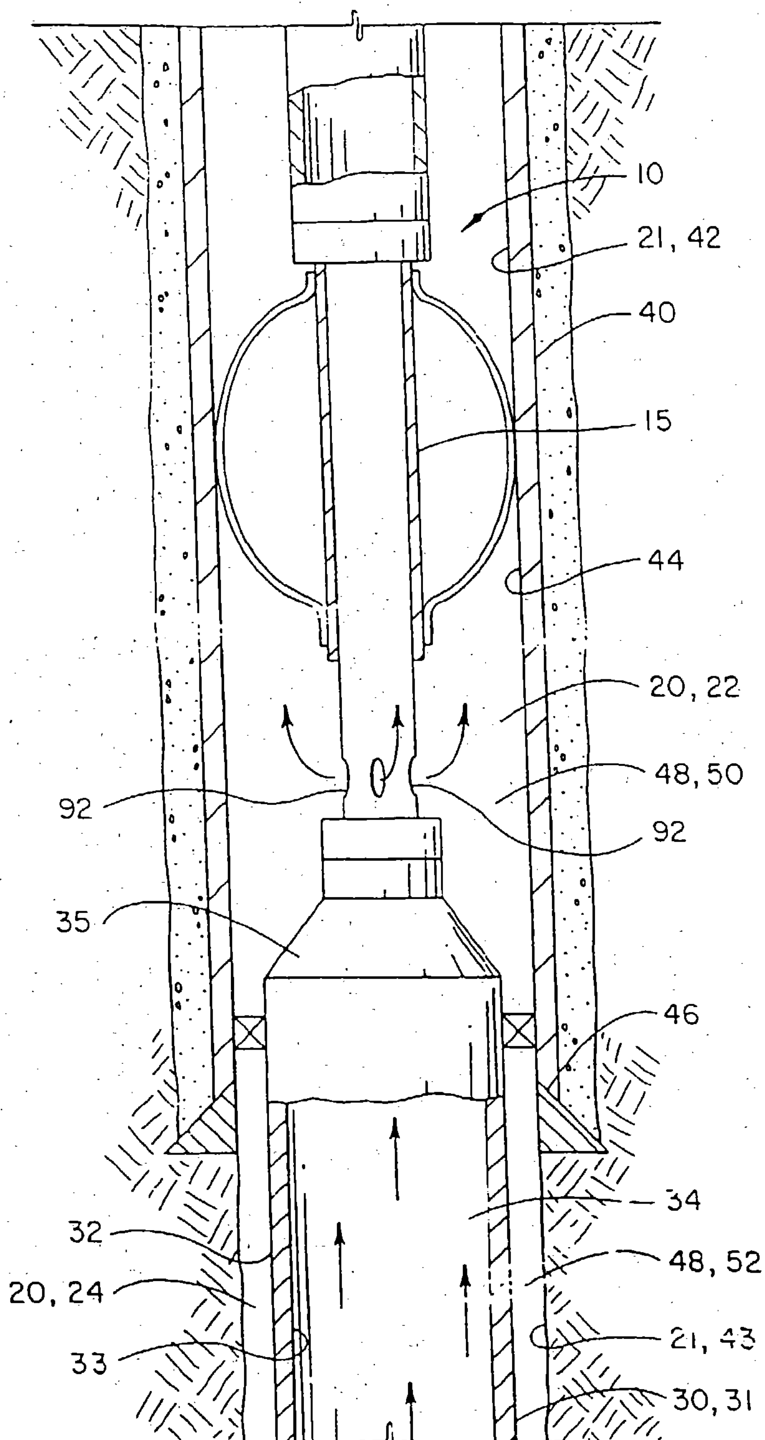
5. An apparatus according to claim 4, wherein said upper locking element (282) is disposed and is moveable in the vertical portion (190) of said slot (88) and is moveable into locking engagement with said slot (88) when said tubular housing (102) rotates relative to said closing sleeve (102).

6. Apparatus according to claim 2 or 3, wherein said upper locking element (282) is biased into engagement with said slots (88) and held in place by a spring (346) disposed about said housing (70).

7. An apparatus according to claim 4, 5 or 6, wherein said upper (282) and lower (280) locking elements are disposed in openings (272; 274) defined in said closing sleeve (102), and preferably wherein said upper (282) and lower (280) locking elements comprise spherical locking elements (182).

8. An apparatus according to any preceding claim, wherein a casing (40) disposed in said wellbore (20) frictionally engages said closing sleeve (102) whereby said closing sleeve (102) is held in place so that said closing sleeve (102) moves relative to said tubular housing along said operating length (161) as said pipe string (10) moves vertically in said casing (40).

9. A method for reducing surge pressure comprises providing a string of pipe having a diverter apparatus (15) according to any preceding claim connected thereto lowering the pipe string (10) including the diverter apparatus (15) into a wellbore (20), allowing wellbore fluids to flow into the pipe string (10) at a point below the diverter apparatus and allowing wellbore fluid received in the pipe string to exit the pipe string through the at least one port (92).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21, 42
40
15
44
20, 22
48, 50
92
92
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46
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32
48, 52
20, 24
21, 43
33
30, 31

FIG-1

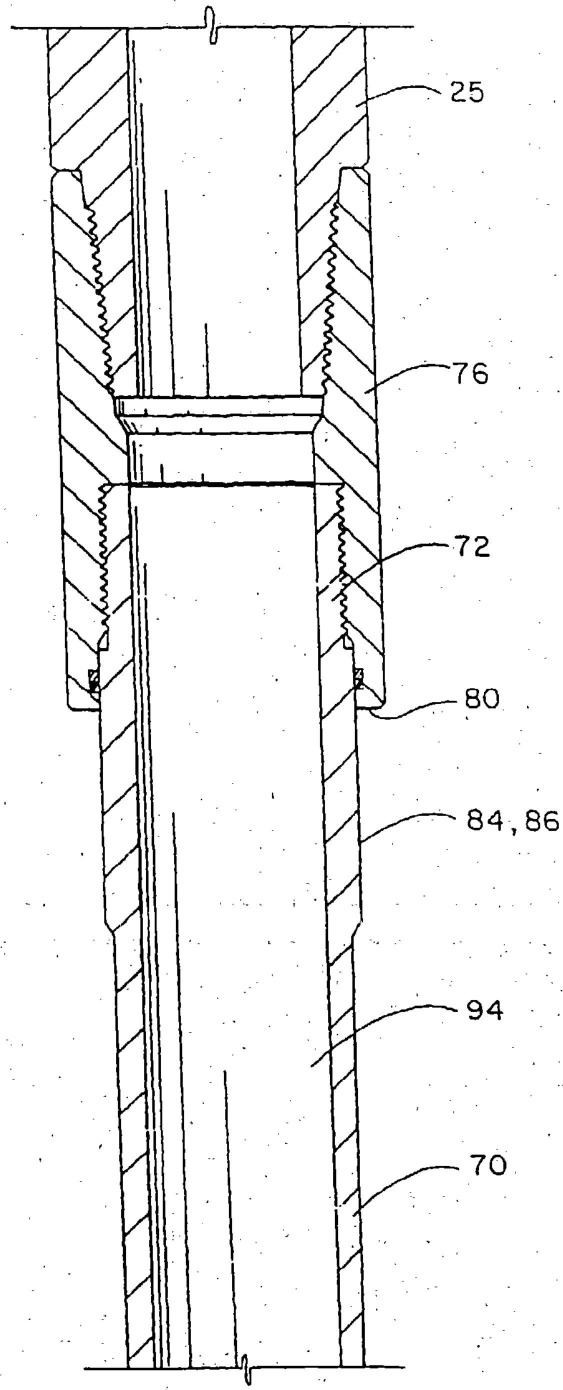
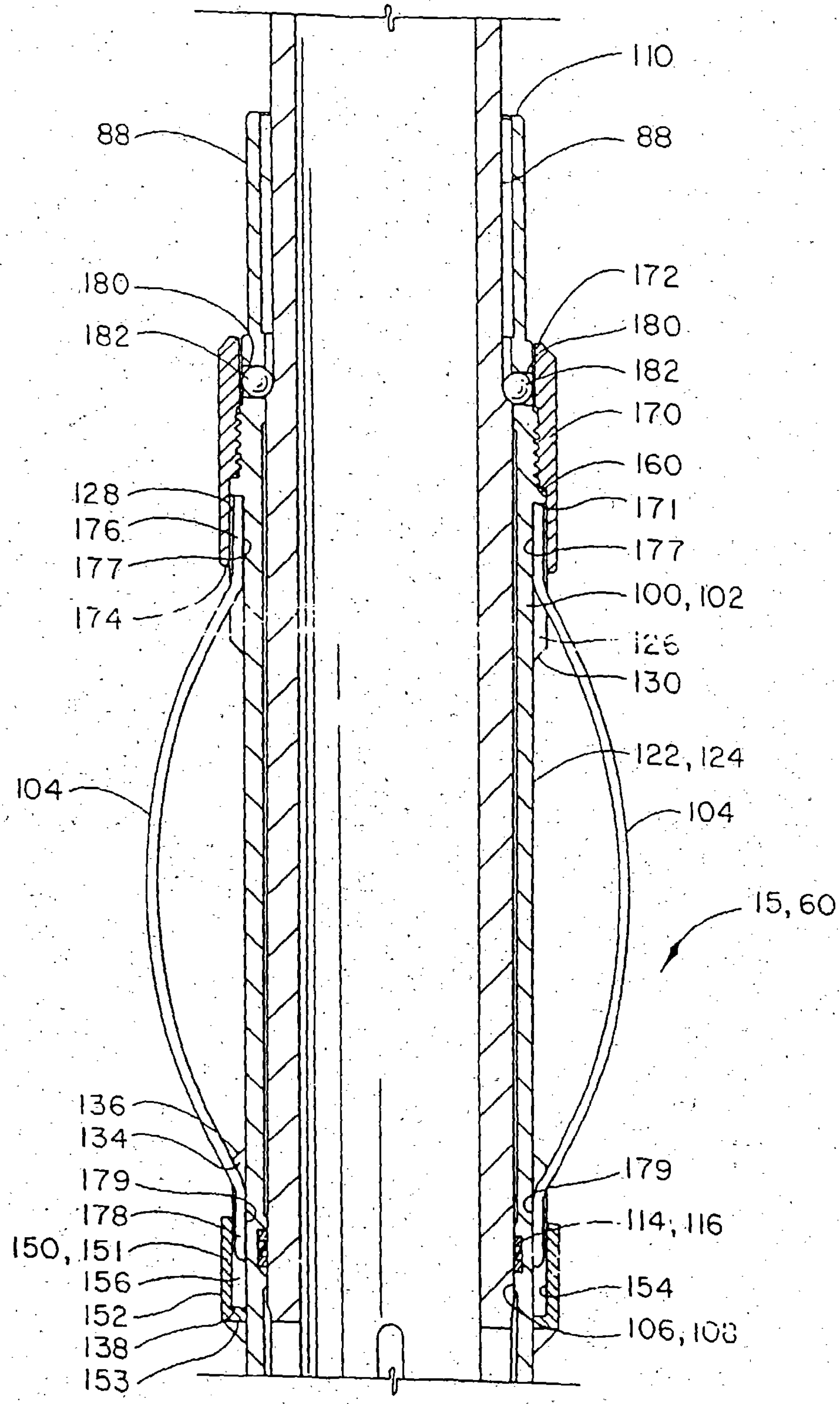


FIG. 2A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177
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174
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122, 124
104
104
15, 60
136
134
179
179
178
114, 116
150, 151
156
154
152
106, 108
138
153

FIG-2B

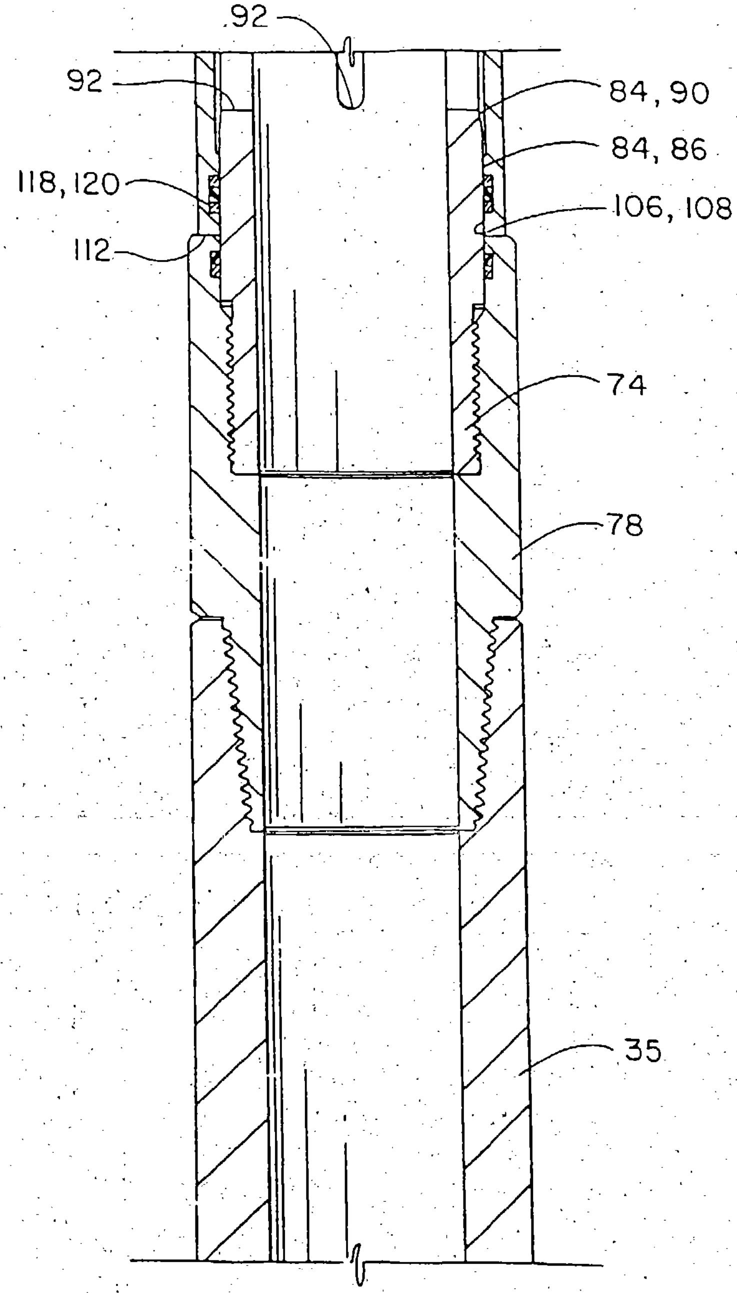


FIG. 20

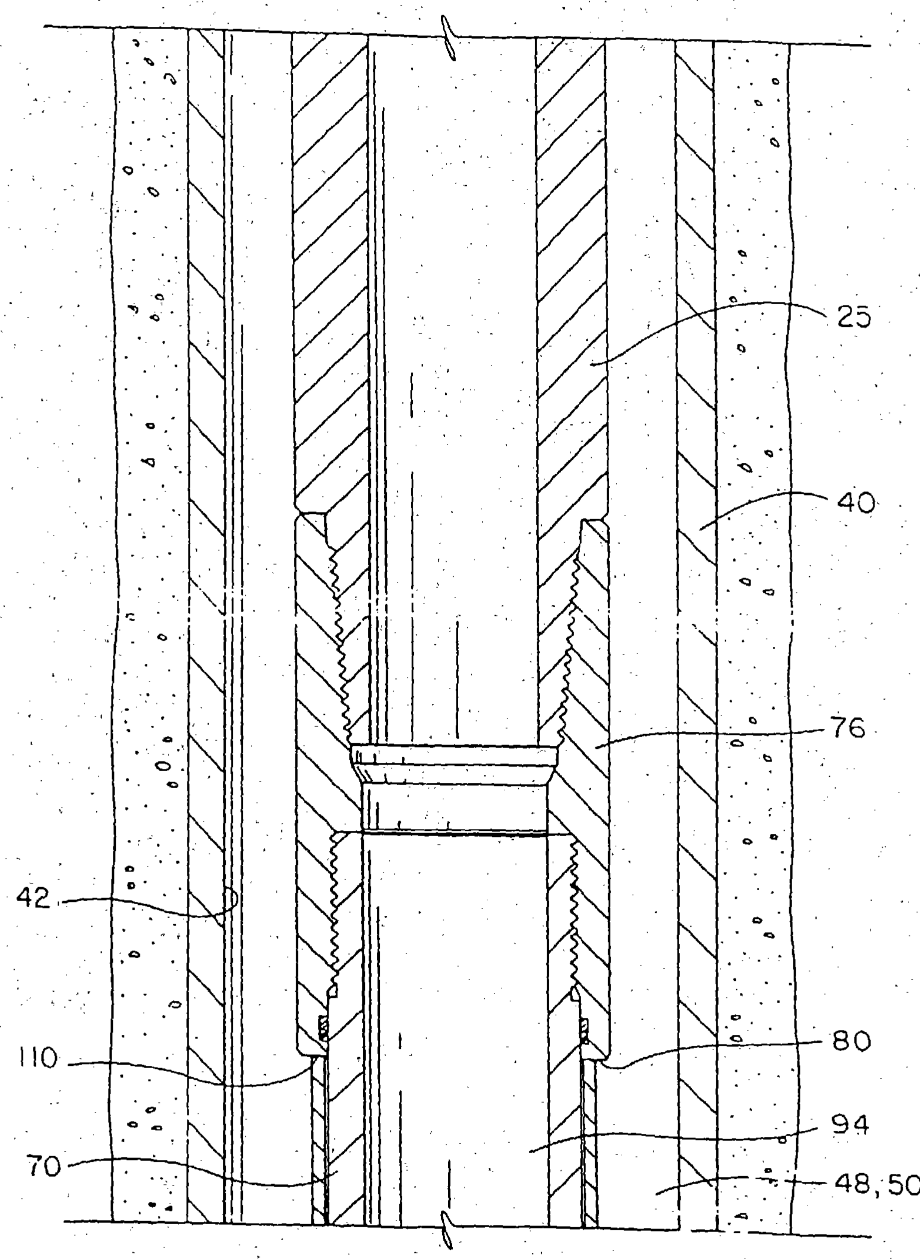
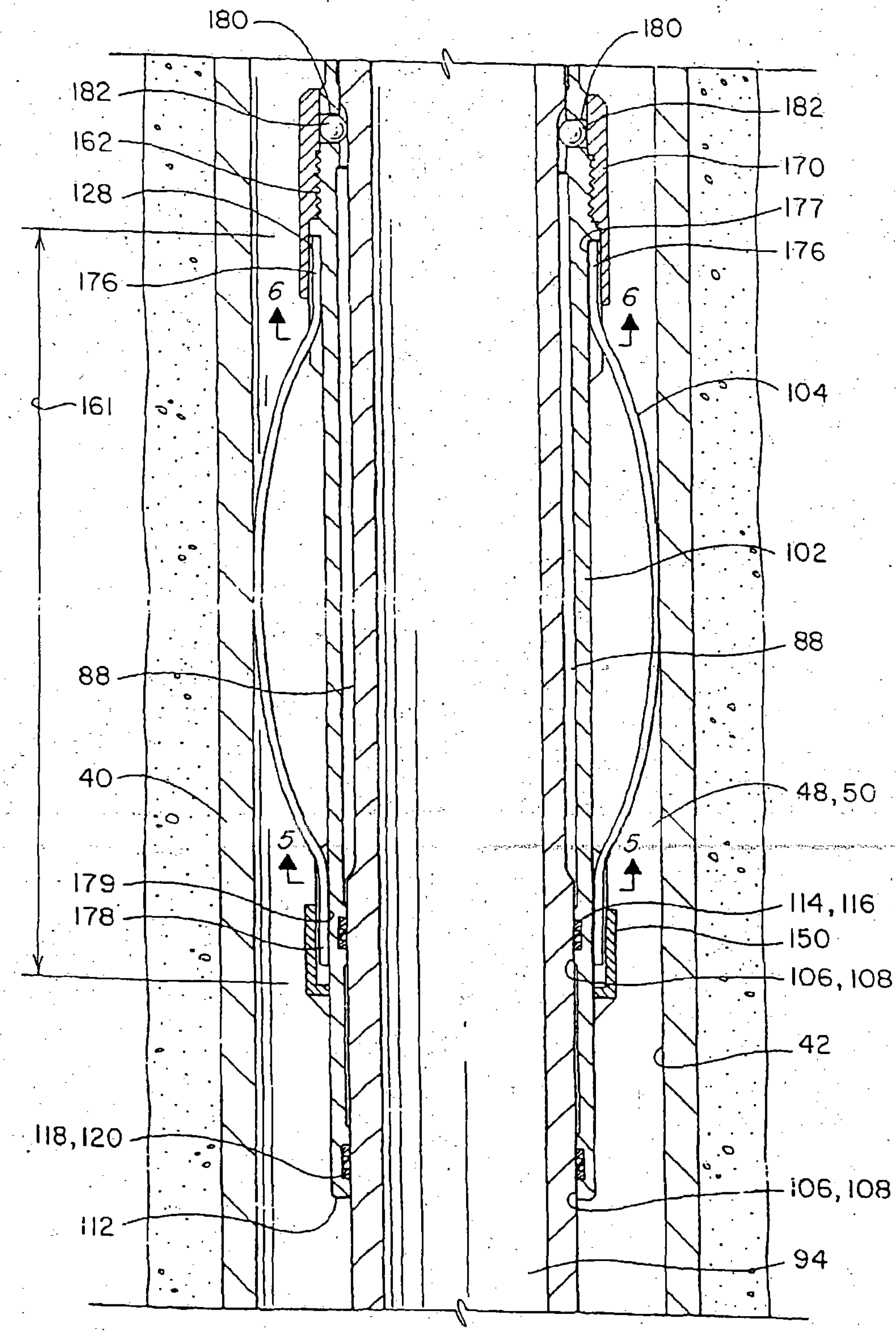


FIG-9A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180
182
182
162
170
128
177
176
176
6
6
161
104
102
88
88
40
48,50
5
5
179
114,116
178
150
106,108
42
118,120
106,108
112
94

FIG. 3B

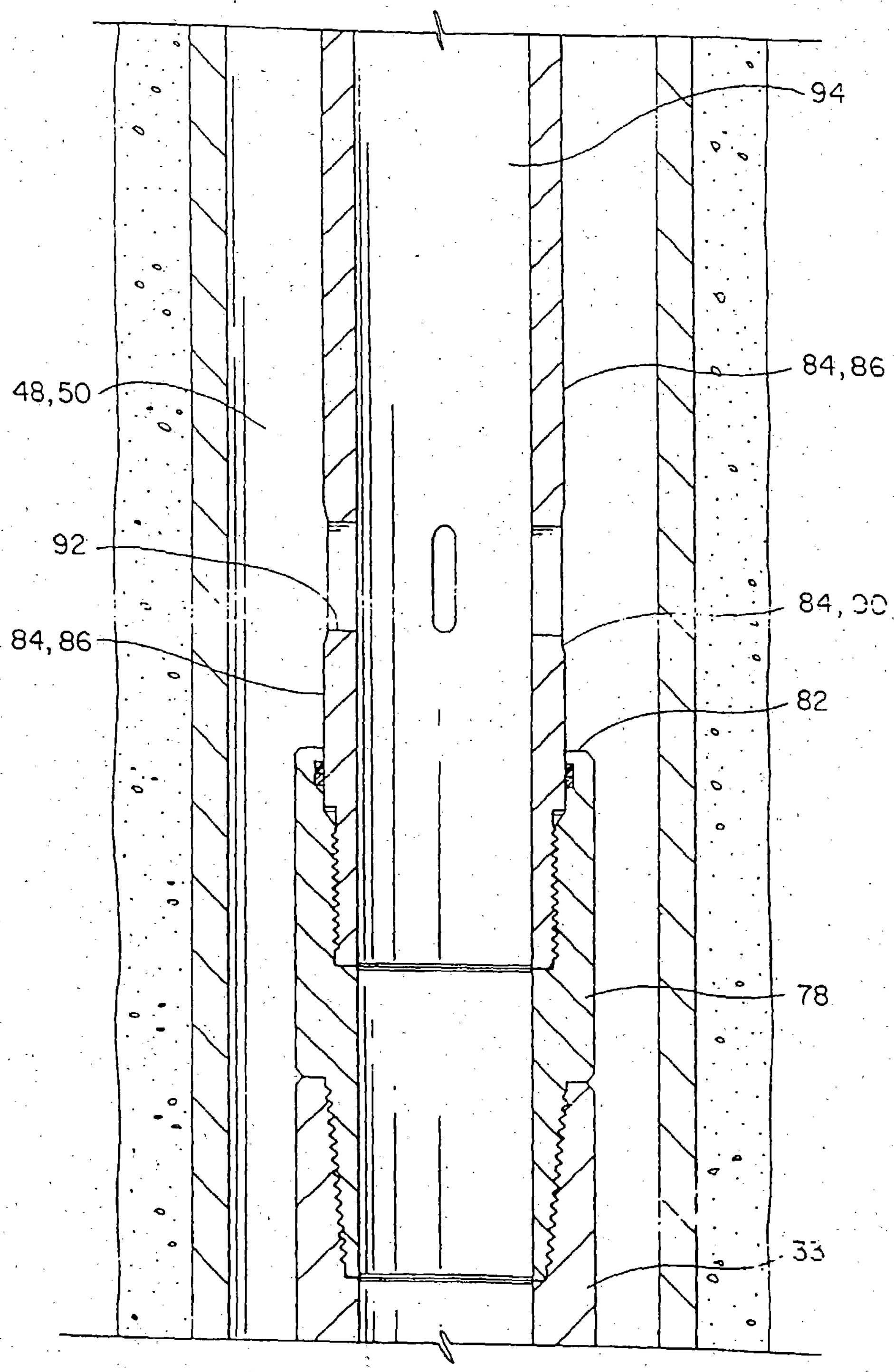


FIG-3C

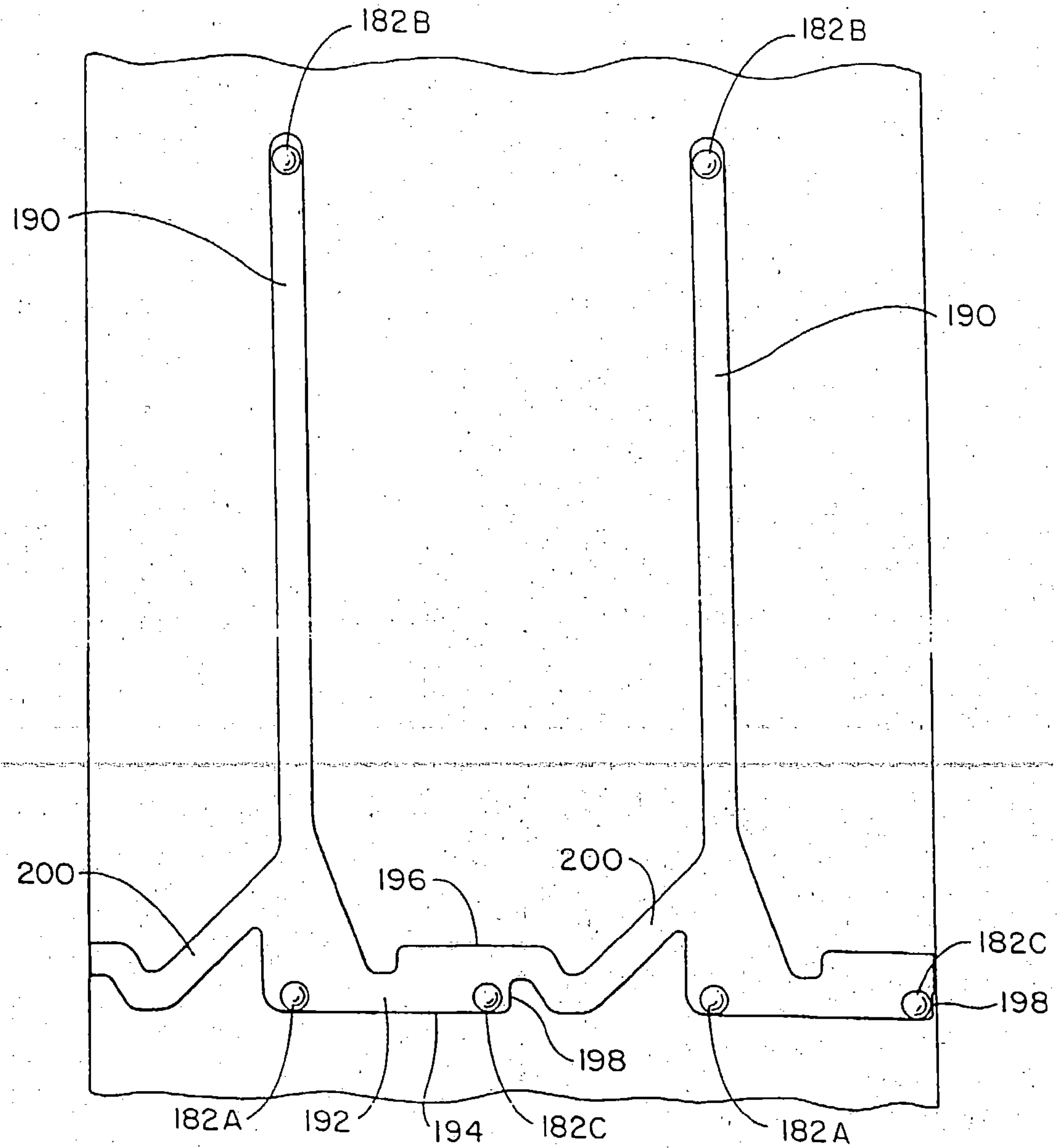
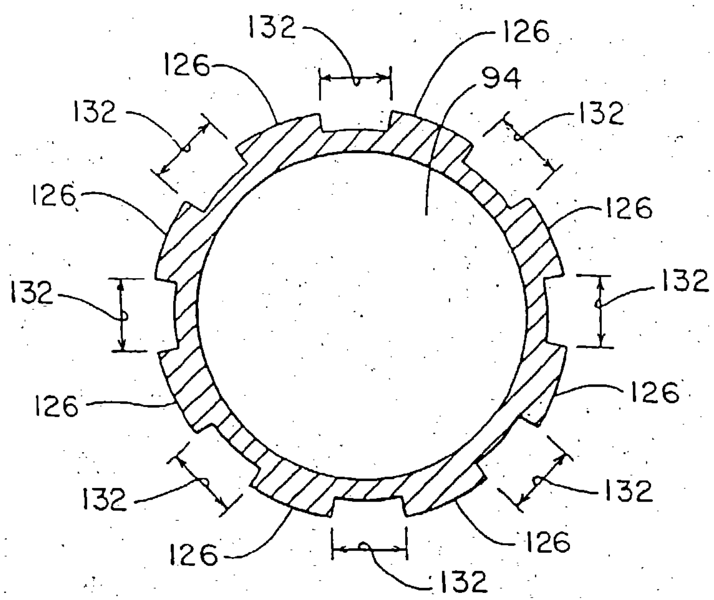

182B
182B
190
190
200
196
200
182C
198
198
182A
192
194
182C
182A

FIG-4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94
132
132
126
126
132
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126
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132
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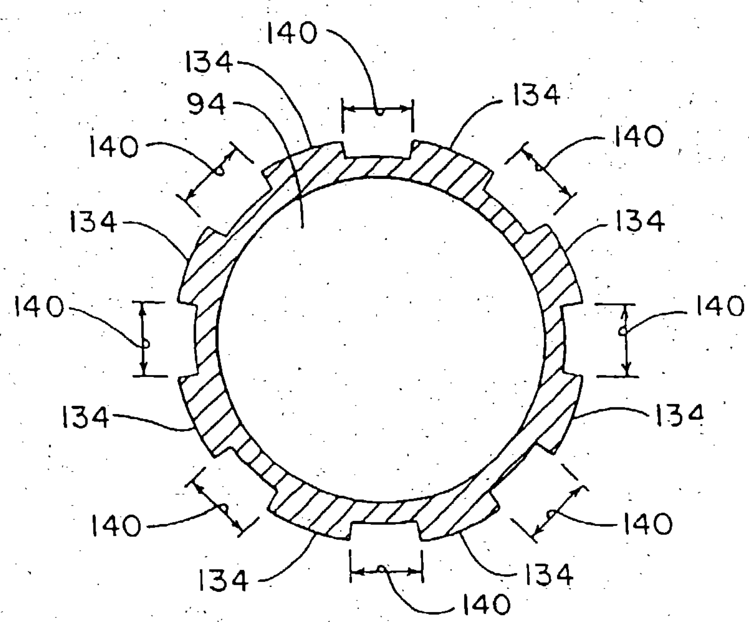
126
126
132

FIG-5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134
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134
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140
140
134
134
140

FIG-6

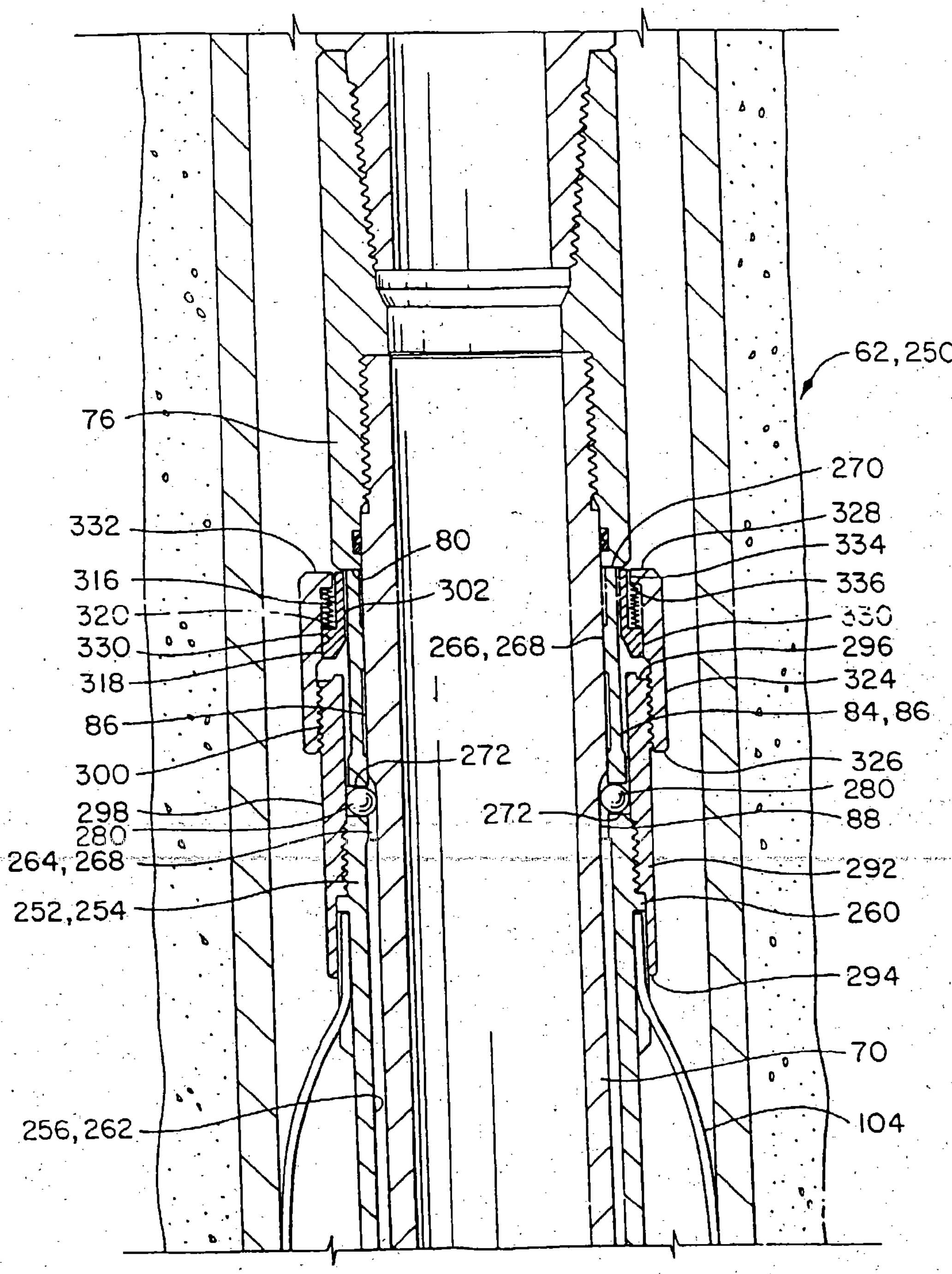
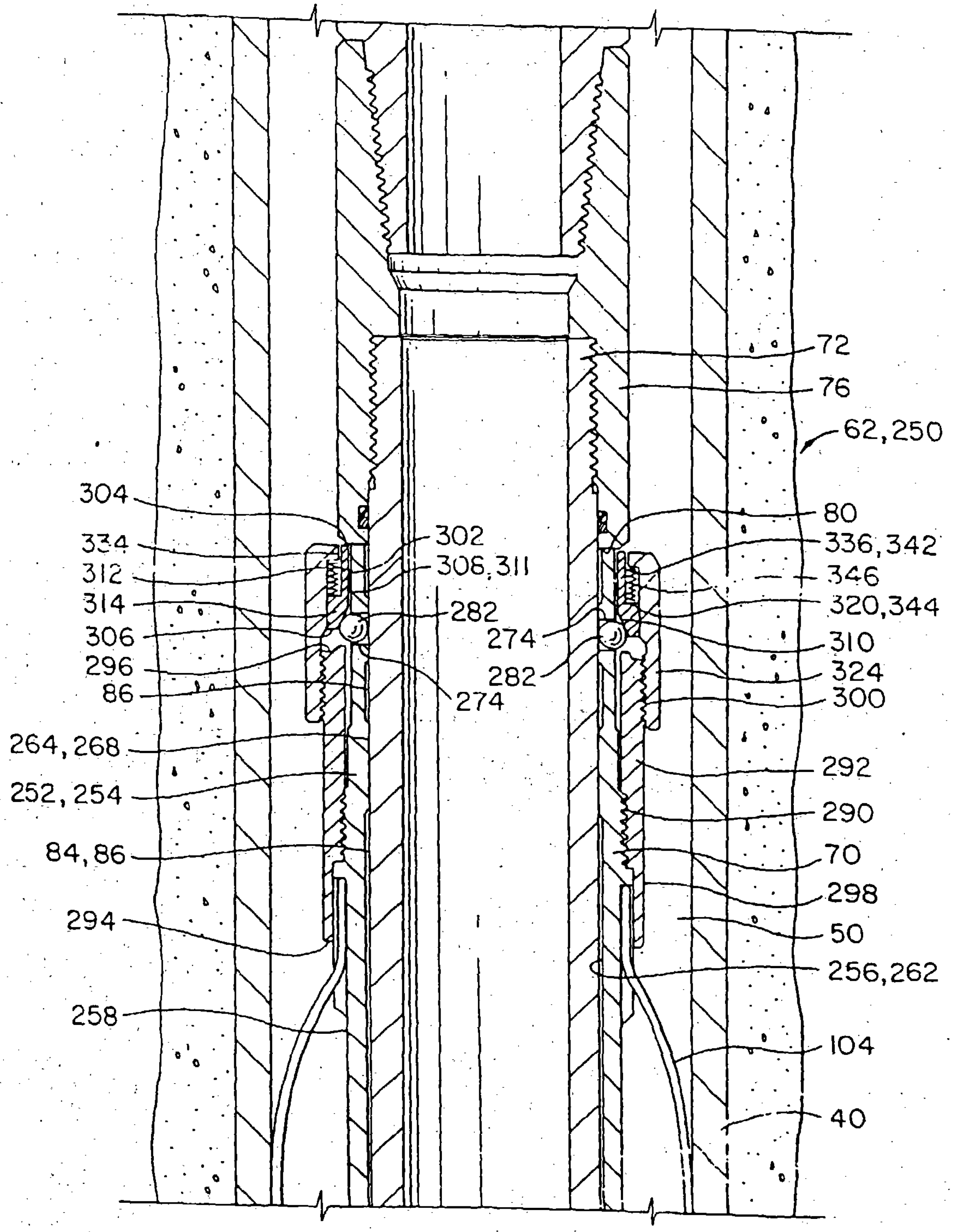

62, 250
76
270
328
332
80
334
316
302
336
320
330
330
266, 268
296
318
324
86
84, 86
300
272
326
280
298
272
88
280
264, 268
292
252, 254
260
294
70
256, 262
104

FIG. 7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334
336,342
302
312
306,311
346
314
282
320,344
306
274
310
296
282
324
86
274
300
264,268
292
252,254
290
84,86
70
298
294
50
256,262
258
104
40

FIG-8

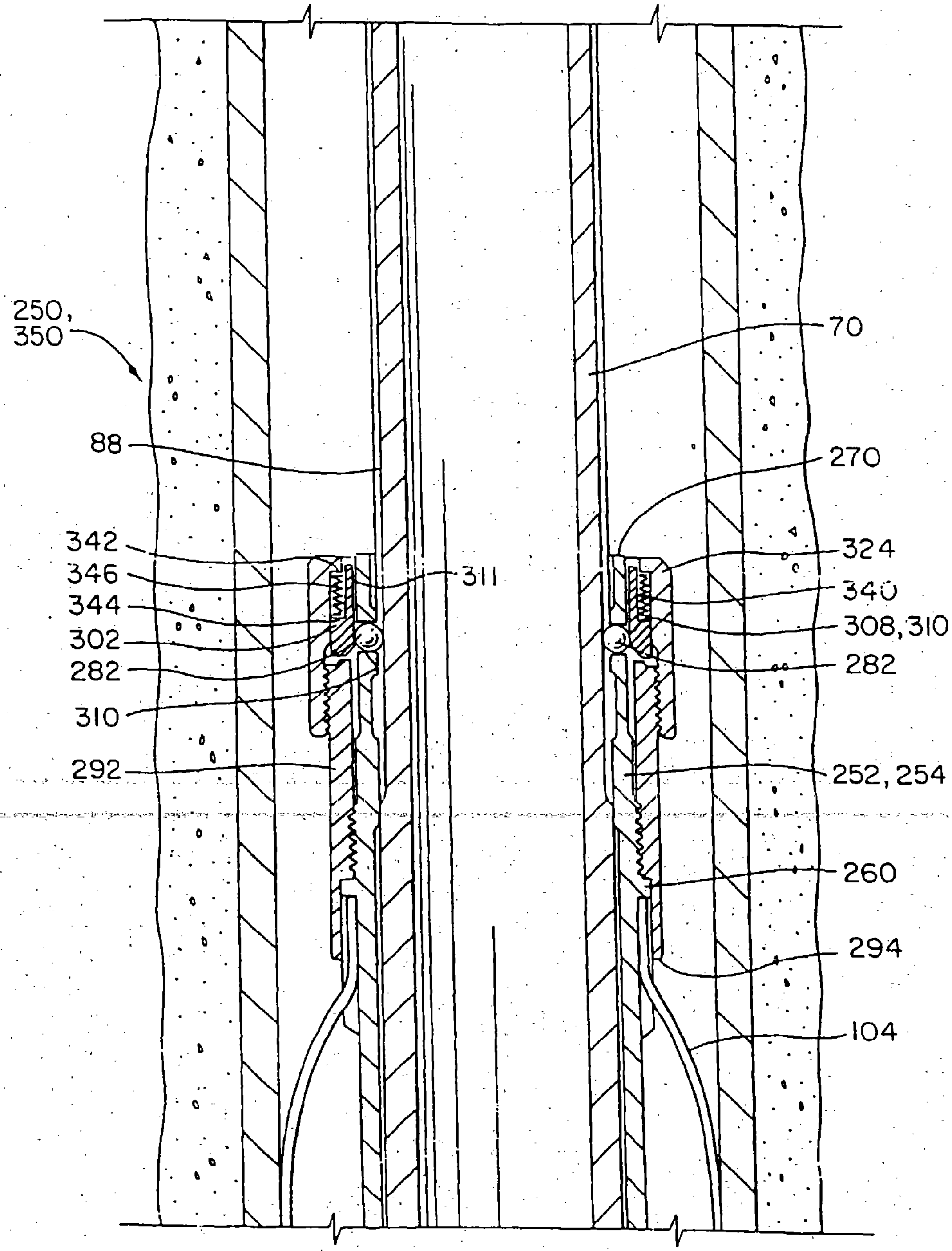
250,
350
88
342
346
344
302
282
310
292
311
70
270
324
340
308,310
282
252,254
260
294
104

FIG - 9

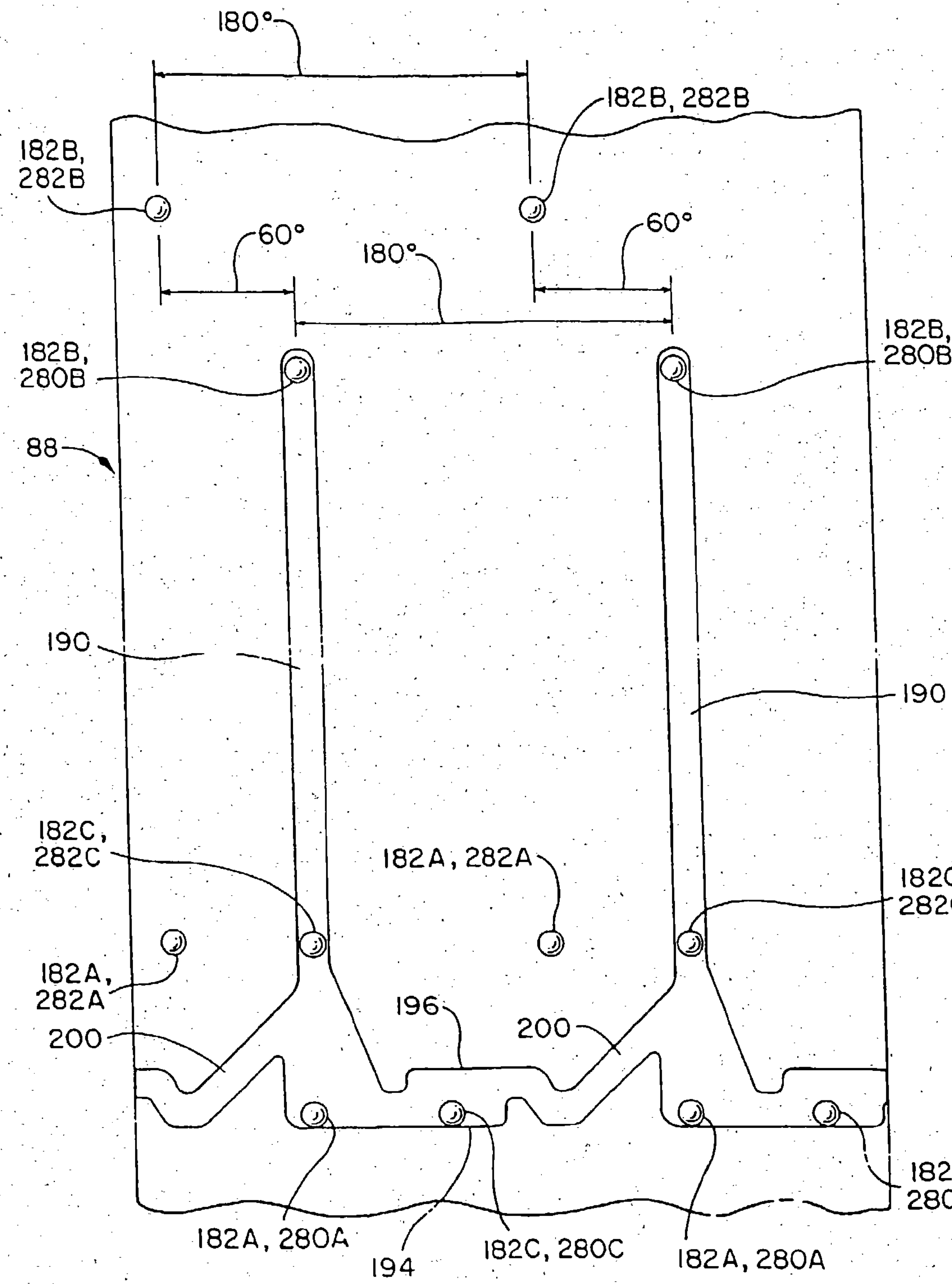
180°
182B, 282B
182B, 282B
60°
180°
60°
182B, 280B
182B, 280B
88
190
190
182C, 282C
182A, 282A
182C, 282C
182A, 282A
196
200
200
182C, 280C
182A, 280A
194
182C, 280C
182A, 280A

FIG. 10